COMPARATIVE ANALYSIS OF INTEGRATED ENERGY PRICING IN INDIA AND BANGLADESH

Interim Report

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BACKGROUND TO THE STUDY

As far as energy was relatively cheap, partial approaches of energy pricing and resulting economic losses were acceptable, but lately with rising energy costs, drastic changes in relative fuel prices and increasing substitution possibilities, the advantages of more integrated energy policies have become evident.

In the absence of an integrated energy pricing, the price of a fuel may be fixed without seriously analysing the impact this may have on the structure of relative prices and hence on the demand for other fuels. For e.g. prices of diesel and electricity are set without any analysis of what is likely to be the impact of these pricing policies on the consumption pattern of these fuels. As a result, the low prices of electricity has discouraged the substitution of other energy sources; notably the renewables. Cross-subsidization of the products has also posed some serious problems. The subsidy on kerosene has made the production of soft coke unprofitable. In addition, to reduce the adulteration of HSD by kerosene, the government has had little choice but to keep the price differential between the two products low. This pricing policy has therefore resulted in further increasing the demand for kerosene and HSD, both of which are middle distillates and are imported.

Thus, we find that in actual practice of fixing fuel prices, interrelations between prices at different stages and those among different fuels are generally ignored. In the absence of an integrated energy pricing framework, the prices of different energy sources do not reflect the true cost to the economy. There are, however, several problems in introducing an integrated energy pricing framework in the country. Chief constraints are: (i) institutional framework and organizational coordination; (ii) inadequate policy instruments; (iii) income disparities, regional development needs and social considerations which call for subsidized energy prices; (iv) market distortions due to taxes, import duties, subsidies or externalities which cause market (or financial) prices to diverge substantially from true economic opportunity costs or shadow prices.

Introducing integrated energy pricing practice calls for reviewing the existing pricing policies of different energy sources as well as analysing the problems and prospects of doing the same. In view of the above, the scope of the study is as given below:

(i) Obtaining background information on the natural energy resource endowments of the two countries, their efforts at developing their resources, their balance of payments and balance of trade situations and outlook, energy supply/demand scenarios and perspectives.

(ii) Analyzing broad trends in energy consumption in various end-use sectors, to gain an understanding of the implications of price movements on use patterns. It is realized however, that our efforts in this direction may be seriously limited owing to the fact that availability of the required energy products has influenced demand patterns considerably, at least in India.

(iii) Deriving an integrated pricing policy based solely on economic criteria. Some efforts to adjust the so derived prices to suit the social and other non-economic considerations, will also be made.

(iv) Studying the institutional mechanisms required for implementing an integrated energy pricing policy.

We are in the process of acquiring the required information from the concerned sources regarding organizational structure and the pricing policies of the primary organizations associated with the energy sector planning and pricing. Information regarding Bangladesh is being obtained from the various organizations in the energy sector.

In this interim report, an analysis of energy resources in India has been attempted in Chapter 1. Chapter 2 gives a broad trend in energy consumption in the various end-use sectors and highlights changes, if any, in the consumption pattern of various sources of energy across different consumer categories. In Chapter 3, the prevailing pricing policies in the coal, petroleum and power sector is briefly outlined. Chapter 4 gives a broad outline of the energy sector in Bangladesh. In view of the limited information regarding the various energy sub-sectors in Bangladesh, analysis of pricing policies is limited to electricity sector only.

Chapter 1

ENERGY RESOURCES AND SUPPLY

India's energy requirements are met from age-old traditional as well as modern forms of energy. The striking characteristic of the Indian energy scene is the dominant role of non-commercial fuels like firewood, cowdung cakes biomass and animate forms of energy. The commercial energy requirement are met primarily by coal, oil and hydropower. Natural gas and nuclear power have also a small share in the primary energy consumption.

1.1 Coal Reserves

Coal is the most important source of commercial energy in India. The country's large coal reserves are concentrated in Bihar, Orissa, West Bengal, Madhya Pradesh, Andhra Pradesh and Maharashtra . These states together account for more than 99 per cent of the total reserves in the country. Indian coals are largely of bituminous grade. Coking and blendable coals amount to less than 16 per cent of the total resources and are found mostly in the eastern region, mainly in Jharia and Raniganj coal fields. Indian coals usually have a low sulphur content but have a high ash content.

Trends in estimated recoverable coal reserves are highlighted in Table 1.1. As is evident from the table, the gross coal reserves have grown from 112 billion tonnes in 1978 to 176 billion tonnes in 1988, thereby indicating addition of 64 billion tonnes of coal during the decade 1978-1988. Most of this increase was in the categories of proved reserves (31 billion tonnes) and indicated reserves (28 billion tonnes), which together accounted for more than 91 per cent of total addition of reserves during the decade. Out of the total coal reserves of 176 billion tonnes in 1988-89, prime coking coal reserves were only 3%. Non-coking coal had the largest share (84 per cent) and medium/semi-coking coal accounted for 13 per cent of the total coal reserves in the country in 1988-89 (see Table 1.2 for details).

Table 1.1: Trends in estimated recoverable reserves: 1975 to 1988

(Billion tonnes)

Year ended December	Gross Reserves	Mineable Reserves
1975	87.3	48.8
1978 (a)	111.8	63.6
1983	120.1	68.1
1984 (a)	148.8	85.9
1985 (b)	155.9	91.4
1986	159.3	98.6
1987	170.5	105.5
1988	176.3	111.2

(a) As on September end
(b) As on June-end
Source: Current Energy Scene In India, July 1989

Table 1.2: Category wise resources of coal (million tonnes) in 1988-89

Type of coal	Proved	Indicated	Inferred	Total
Prime Coking	4171	1129	-	5300
Medium/Semi-Coking	9333	11388	1684	22405
Non-Coking	38631	61674	48320	148625

Source: Ministry of Energy, op cit Ref Table 2.1.1

1,2 Coal production

At the time of independence, coal industry was almost entirely managed by the private sector. The industry was fragmented into about 900 mines most of which were too small to run the industry on a rational basis. In 1971, all the coking coal mines were nationalised. Non-coking mines were nationalised in 1973.

An integrated development programme for the coal industry was initiated after its nationalization in 1973, as a result of which there was marked improvement in coal production. During the period 1973 to 1976, the rate of increase in production improved to about 9 percent per annum. This was followed by a period of stagnation in the latter half of the 1970's when production increased at only 2 percent per annum. Coal production registered a compounded growth rate of 8.1 percent during the period 1980-88 when coal production increased from about 104 million tonnes to about 180 million tonnes.

Table 1.3: Trends in coal production 1975-76 to 1987-88

(Million tonnes)

Period	Coking	Non-coking	Total
1975-76	22.19	77.49	99.68
1979-80	23.50	80.45	103.95
1985-86	35.65	118.59	154.24
1986-87	39.53	126.24	165.77
1987-88	41.08	138.67	179.75

Source: TEDDY 1989

One of the important factors which contributed to rapid growth of coal production was adoption of opencast mining technology during the post nationalisation period. The proportion of opencast coal mining which was 20 per cent in 1970/71 increased to 26 per cent in 1973-74 and further to 50 per cent by the end of Sixth Plan period in 1984-85. In 1986-87, the share of production from open-cast mines was 67.5 per cent

1.3 Oil reserves

By comparison with coal, proved reserves of hydrocarbons in India are at present exceedingly small. India has prognosticated hydrocarbon reserves of the order of 17 billion tonnes, 48 per cent of these reserves are contained in the three basins of upper Assam, Bombay High and Cambay (Gujarat). However, only 25 per cent of the total reserves are proven, and further not all of it can be recovered in practice. Trends in proven and balance recoverable reserves of crude oil is shown in Table 1.4. In 1966, total recoverable reserves of crude oil was 153 MMT, all of which was on-shore. Reserves of crude oil declined from 153 MMT in 1966 to 124.5 MMT in 1974. However, discovery of Bombay High (off-shore) crude oil reserves in 1975 led to a massive increase in total oil reserves from 144 MMT in 1975 to 276 MMT in 1976. In percentage terms, the share of Bombay High in total reserves increased from 54 per cent in 1976 to 70 per cent in 1981. In 1988, Bombay High reserves increased by 12 per cent, resulting in a marginal increase in its share in total reserves (after accounting for increased production from this area).

Table 1.4: Proved and indicated balance recoverable reserves of crude oil and natural gas

Year	Crude Oil (Million Tonnes)			Natural Gas (bcm)		
	On shore	Off shore	Total	On shore	Off shore	Total
1970	127.84	-	127.84	62.48	-	62.48
1975	130.13	13.77	143.90	81.39	6.28	87.67
1976	127.78	147.68	275.46	78.26	106.62	184.88
1981	140.48	328.29	468.77	81.61	329.04	410.65
1983	187.61	338.70	526.31	98.05	377.21	475.26
1985	188.41	311.10	499.51	110.08	368.55	478.63
1987	251.08	330.35	581.43	139.82	400.99	540.81
1988	267.40	371.04	638.44	168.38	411.09	579.47

Source : Department of Petroleum and Natural Gas, op cit Ref. Table 2.2.2.

1.4 Crude oil production

In the 1980's crude oil production increased from 10.5 million tonnes in 1980-81 to 21.1 million tonnes in 1982-83 and further to 30.2 million tonnes in 1985-86. Most of the increase was from Bombay High where production increased from 5 million tonnes to 12.9 million tonnes in 1982-83 and further to 20.6 million tonnes in 1987-88 (see Table 1.5 for details).

Table 1.5: Trends in production of crude oil and natural gas

Year	Crude oil ('000 Tonnes)			Natural gas (mcm)		
	On shore	Off shore	Total	On shore	Off shore	Total
1970/71	6822	0	6822	1445	0	1445
1976/77	8492	406	8898	2380	48	2428
1977/78	8689	2074	10763	2610	229	2839
1980/81	5522	4985	10507	1685	673	2358
1982/83	8186	12877	21063	2579	2357	4936
1984/85	8854	20136	28990	2833	4408	7241
1986/87	9856	20618	30474	3148	6705	9853
1987/88	10193	20614	30357	3208	8259	11467

Source: Department of Petroleum and Natural Gas, op cit Ref. Table 2.2.2.

Ratio of proven and balance recoverable reserves to production doubled from 15.83 in 1971 to 31.81 in 1976. It fluctuated between 27 to 30 during the period 1977 to 1979 and rose to 39 in 1980. Since then, however, there has been a sharp decline in this ratio (refer to table 1.6 for details).

Table 1.6: Ratio of proven and balance recoverable reserves to production

Year	Crude oil	Natural gas
1971	15.83	41.28
1976	31.81	75.83
1980	38.97	169.43
1982	23.81	90.07
1984	18.29	70.12
1986	17.91	52.53
1987	19.29	49.59

Source : Department of Petroleum and Natural Gas, op cit Ref. Table II.2.2

The refining capacity in the country has increased keeping pace with the rising demand for petroleum products. Crude throughput in the refineries rose from the level of 25.85 million tonnes in 1980-81 to 47.75 million tonnes in 1987-88. The capacity utilization has been consistently high, particularly since 1983-84, and reached a high of 98 per cent in 1987-88 (see Table 1.7 for details).

1.5 Natural gas reserves

Natural gas has been emerging as a fast expanding important source of commercial energy. The natural gas reserves are concentrated mainly in Bombay High, Gujarat and Assam. Rajasthan too has some small natural gas reserves. India's balance

Table 1.7: Refining industry - crude throughput & production of petroleum products

	1975/76	1979/80	1981/82	1983/84	1985/86	1986/87	1987/88
Crude Throughput ('000t)	22283	27474	30146	35263	42910	45698	47744
Capacity Utilization (%)	76	81.1	76.9	87.1	87.5	91.6	98
Production ('000t)	20829	25794	28182	32926	39881	42776	44634
Refinery Losses ('000t)	1454	1680	1964	2337	3029	2922	3110
% Losses	6.5	6.1	6.5	6.6	7.1	6.4	6.5

Source : Department of Petroleum and Natural Gas, op cit Ref. Table 2.2.2

recoverable reserves of natural gas have increased almost nine-fold during the last 21 years. There was a sudden jump in the gas reserves in 1976 as a result of discovery of Bombay High. Off-shore balance recoverable reserves of natural gas increased from 6.28 bcm in 1975 to 106.62 bcm in 1976, i.e. by almost 100 bcm (Refer to Table 1.4). In 1976, the share of Bombay High in proven and balance recoverable reserve was 57.6 per cent and it increased to 80 per cent in 1981. Since then, however, the share of off-shore balance recoverable reserves has been declining every year.

Of the total on-shore natural gas reserves, major proportion is located in Assam followed by Gujarat. Share of natural gas reserves in Assam increased from 68.5 per cent in 1970 to 80 per cent in 1975 and remained more or less stable in the following 10 years. Since 1985, however, this share has been declining at a very fast rate. On the other hand, the share of natural gas reserves in Gujarat has been on an increase since 1985. Proven and recoverable natural gas reserves in Rajasthan is very small.

1.6 Natural gas production

A noteworthy feature in the supply of the primary sources of commercial energy during the last one and a half decade has been the rapid rise in natural gas production. The share of natural gas in the total supply of primary sources of commercial energy has increased from about 2 percent in 1970-71 to more than 6 percent by 1987-88. Table 1.5 shows that indigenous natural gas production nearly doubled from 1445 mcm in 1970-71 to 2839 in 1977-78. Between the period 1978-79 to 1980-81, there was a decline in the natural gas produced in the country; primarily because of the decline in natural gas production in Assam, where the major gas reserves are located. Natural gas production jumped up by 63 per cent in the following year, (1981-82) and has been going up since then. In 1987-88, 11.4 bcm of natural gas was produced, of which, 8.259 bcm (72 percent) was offshore and 3.208 (28 percent) was onshore.

1.7 Electricity

The power supply industry has registered a phenominal growth during the last four decades. The power generating capacity of the country has grown up at an average rate of 9.7 per cent per annum since independence. The installed generation capacity has increased from 2300 MW in 1950 to 59588 MW by the end of 1988-89. Of the 59588 MW commissioned until March 31, 1989, more than 50 per cent had been added during the past ten years alone. The overall trend in the installed capacity from 1950 to 1988-89 is shown in table 1.8. The hydro-thermal mix has changed substantially since the early 1970s. In 1970-71, the share of

Table 1.8: Installed capacity in utilities (MW)

Year	Hydel	(%)	Thermal	(%)	Nuclear	(%)	Total
1950	559.29	32.65	1153.23	67.34		0	1712.52
1955	939.48	34.86	1755.34	65.13		0	2694.82
1960/61	1916.66	41.19	2736.39	58.80		0	4653.05
1965/66	4123.74	45.68	4903.28	54.31		0	9027.02
1970/71	6383.23	43.39	7905.72	53.74	420	2.85	14708.95
1975/76	8463.60	42.07	11013.46	54.74	640	3.18	20117.06
1980/81	11791.22	39.02	17562.46	58.12	860	2.84	30213.68
1985/86	15471.60	33.08	29967.43	64.07	1330	2.84	46769.03
1986/87	16195.64	32.80	31740.22	64.42	1330	2.69	49265.86
1987/88	17215.09	31.70	35650.22	65.65	1330	2.44	54295.31
1988/89	17586.40	29.51	40671.50	68.25	1330	2.23	59587.90

Source : (1) CEA, Public Electricity Supply, All India Statistics General Review, various issues ; (2)CEA, Power Supply Position in the country, Vol 17, No.5, May 1989

Table 1.9: Trends in annual gross generation in utilities (MU)

Year	Hydel	(%)	Thermal	(%)	Nuclear	(%)	Total
1950	2519.77	49.34	2586.93	50.65		0	5106.70
1955	3742.24	43.55	4850.21	56.44		0	8592.45
1960/61	7836.58	46.26	9100.43	53.73		0	16937.01
1965/66	15224.97	46.15	17765.15	53.84		0	32990.12
1970/71	25248.24	45.22	28162.02	50.44	2417.38	4.33	55827.64
1975/76	33301.77	42.03	43302.64	54.65	2626.10	3.31	79230.51
1980/81	46541.76	41.98	61300.86	55.30	3001.34	2.70	110843.90
1985/86	51020.78	29.95	114347.47	67.12	4981.88	2.93	170350.13
1986/87(a)	53851.18	28.67	128925.50	68.65	5021.94	2.67	187798.60
1987/88(b)	47396.00	23.47	149469.00	74.03	5029.00	2.49	201894.00
1988/89(b)	57742.00	26.13	157436.00	71.24	5800.00	2.62	220978.00

(a) Provisional ; (b) Tentative

Source : CEA, General Review, op cit Ref. Table 2.3.1;
CMIE, op cit Ref. Table 2.3.4

installed hydro capacity was 43 per cent. By 1980-81, its share had fallen to 39 per cent and by 1988-89, it reduced further to 29.5 per cent. The compound annual rate of growth of the installed hydro-capacity declined from 12.8 per cent during the period 1960-61 and 1970-71 to 6.3 per cent during the period 1970-71 and 1980-81, and further to 4.9 per cent during the period 1978-79 and 1988-89. India has also expanded its nuclear, and small hydro capacity over the past two decades. Presently nuclear power accounts for 2.2 percent of the total installed utility capacity. As on May 1989, 111 micro/mini/small hydro stations with an aggregate capacity of 201 MW, are in operation in the country.

The gross power generation has increased from 5107 MU in 1950 to 201753 MU in 1987-88, registering an average growth rate of 10 per cent per annum. Gross generation has nearly doubled during the nine year period 1980-81 through 1988-89 (see table 1.9 for details). The mix between thermal and hydro-electric generation has also changed substantially, particularly since 1970-71. While the ratio of hydro to thermal generation varied between 1:1 and 1:1.25 during the 1950s and 1960s, it began to decline steadily during the 1970s. In 1986-87, the ratio was 1:2.4, and in 1988-89, it was 1:2.7. In 1988-89, gross nuclear power generation in the country was 2.6 percent of total utility generation.

Chapter 2

TRENDS IN COMMERCIAL ENERGY CONSUMPTION IN INDIA

2.1 Commercial energy consumption

During the last four decades, the consumption of commercial energy in the country has grown at an average annual rate of 6.5 per cent per annum, against the rate of growth of 3.5 per cent per annum of the national income. Table 2.1 shows an upward trend in the commercial energy consumption in the Indian economy. The share of commercial energy in total gross energy consumed has increased significantly form 25.6 per cent in 1953-54 to 55.5 per cent in 1987-88. Though the consumption of commercial forms of energy has been growing rapidly and the share of traditional forms of energy in overall energy consumption has been diminishing, the non-commercial fuels still contribute little less than half (45 percent) of the total energy requirements. Traditional energy resources meet most of the energy need for cooking of the rural households, which still constitute a major share of the energy needs of the country.

Table 2.1: Commercial and non-commercial energy consumption

Period	(GCAL/year) Commercial	Non-commercial	Total	Share of commercial energy (%)
1953-54	0.572	1.670	2.242	25.6
1960-61	0.734	1.690	2.424	30.3
1965-66	0.998	1.660	2.658	37.6
1970-71	1.067	1.604	2.671	40.0
1975-76	1.294	1.614	2.908	44.5
1980-81	1.420	1.559	2.979	47.7
1984-85	1.580	1.432	3.012	52.5
1987-88	1.785	1.434	3.219	55.5

Table 2.2 gives details of share of consumption of different commercial energy sources. It is seen that till the mid sixties, coal was the prime source of commercial energy. Its share in total energy consumed in the economy was as high as 68.50 per cent (in mtoe) in 1960-61. As against this, the share of electricity was 6 per cent. However, since mid sixties, coal consumption as a direct energy source has been on a decline, where as the consumption of oil and electricity has increased. Direct use of coal is being gradually replaced by its indirect use through power generation. Over the past two decades natural gas has emerged as an important source of commercial energy. Its share in commercial energy consumption has gone up from 1 per cent in 1972-73 to 4.39 per cent in 1987-88.

Table 2.2: Share of commercial energy sources in total consumption (percent)

Year	Coal	Oil	Electricity	Gas
1960-61	68.50	25.53	5.97	0
1965-66	61.66	30.21	8.13	0
1972-73	58.00	34.80	6.20	1.00
1975-76	60.23	31.75	6.73	1.29
1980-81	57.01	34.31	7.30	1.38
1985-86	57.07	32.07	7.69	3.18
1987-88	56.62	31.19	7.80	4.39

Among the main sectors of the economy, the industrial sector is the major consumer of commercial energy. Industry consumes about 40 per cent of the total final commercial energy. Transport sector is the second largest consumer of commercial energy and accounts for 30 per cent of the commercial energy consumed. Energy consumption in the agricultural sector has increased from 3 per cent in 1953-53 to 10 per cent in 1984-85. There has been a

Table 2.3: Sector-wise consumption of commercial energy in the Indian economy: 1953-54 to 1984-85

Year	Household	Agriculture	Industries	Transport	Others	Total
A: Total consumption of commercial energy absolute data (In million tonnes of coal replacement)						
1953-54	12.7	1.8	22.4	21.5	1.7	60.1
1960-61	20.8	3.6	39.7	34.2	2.9	101.2
1970-71	35.5	9.1	76.3	64.6	11.8	197.2
1978-79	40.3	31.3	113.4	93.2	16.1	294.3
1979-80*	64.1	38.4	156.0	134.0	17.2	409.7
1984-85*	98.9	52.6	220.5	169.5	22.9	564.4
B: Share of different sectors in (A) above (%)						
1953-54	21.3	3.0	37.3	35.8	2.8	100.2
1960-61	20.6	3.6	39.2	33.8	2.8	100.0
1970-71	18.0	4.6	38.7	32.7	6.0	100.0
1978-79	13.7	10.6	38.5	31.7	5.5	100.0
1979-80	15.7	9.4	38.2	32.8	3.9	100.0
1984-85	18.2	9.8	36.4	31.4	4.2	100.0
C: Sector-wise share of coal consumption (%)						
1953-54	7.6	-	48.1	42.2	2.1	100.0
1960-61	8.4	-	47.1	42.5	2.0	100.0
1970-71	7.9	-	60.5	31.0	0.6	100.0
1978-79	5.8	-	73.4	18.0	2.8	100.0
1984-85	3.0	-	78.0	13.0	6.0	100.0
D: Sector-wise share of oil consumption (%)						
1953-54	41.1	6.8	15.3	36.8	-	100.0
1960-61	37.7	6.2	16.5	39.6	-	100.0
1970-71	28.4	4.6	11.2	48.6	7.2	100.0
1978-79	20.3	13.7(a)	6.4	55.4*	4.2	100.0
1984-85	29.0	10.0	5.0	56.0	-	100.0
E: Sector-wise share of electricity consumption (%)						
1953-54	9.2	2.6	65.8	7.9	14.5	100.0
1960-61	8.9	4.7	68.7	4.7	13.0	100.0
1970-71	7.9	9.3	70.7	2.7	9.2	100.0
1978-79	9.1	14.2	63.8	3.1	9.8	100.0
1984-85	11.0	16.0	62.0	2.0	9.0	100.0

* CMIE estimate

Table 2.4: Relative shares of different forms of commercial energy in the various sectors of the economy: 1953-54 to 1978-79

	1953-54	1960-61	1970-71	1978-79
A: Household				
Coal	17.3	13.5	11.5	10.0
Oil	77.2	79.3	77.7	71.2
Electricity	5.5	7.2	10.8	18.8
B: Agriculture				
Coal	0.0	0.0	0.0	0.0
Oil	89.0	77.4	49.8	61.8
Electricity	11.0	22.6	50.2	38.2
C: Industry				
Coal	61.5	52.6	40.7	44.5
Oil	16.2	18.2	14.3	7.9
Electricity	22.3	29.2	45.0	47.6
D: Transport				
Coal	56.4	46.8	24.6	13.3
Oil	40.8	50.8	73.2	83.9
Electricity	2.8	2.4	2.2	2.8
E: Others				
Coal	35.3	24.1	2.6	11.9
Oil	0.0	0.0	59.2	36.2
Electricity	64.7	75.9	38.2	51.9

Source: (i) Report of the Working Group on Energy Policy, 1979.
(ii) The Seventh Five Year Plan: 1985-90.

marginal decline in the share of household sector; the share has declined from 21.3 per cent in 1953-54 to 18.2 per cent in 1984-85 (see table 2.3 for details).

2.2 Energy consumption by end-use

The relative share of different forms of commercial energy in the various sectors of the economy has changed gradually over time. Details of the pattern of energy consumption by end-use from 1953/54 to 1978-79 are shown in Table 2.4.

Domestic sector: While the traditional energy fuels are normally used for cooking and water heating, commercial energy is used for lighting, cooking and running other appliances (such as television sets, refrigerators etc.) as well. Oil and gas is the main source of commercial energy in the residential sector; it accounts for more than 70 per cent of the commercial energy consumed by this sector. In 1953-54, share of coal and electricity consumption in residential sector were 17.3 per cent and 5.5 per cent respectively. However, by 1978-79, the share of electricity consumption had increased to 18.8 percent.

Increase in the share of oil consumption is primarily due to increased use of kerosene and LPG for cooking and water heating. Its share in consumption for the purpose of cooking and water heating has increased from 18.7 per cent in 1978-79 to 35.7 per cent in 1983-84. On the other hand, the share of fuelwood and soft coke declined from 42.4 per cent and 18.4 per cent to 27.4 per cent and 15.3 per cent respectively during the same period. There has also been gradual increase in the consumption of LPG for cooking and water heating. The share of LPG in cooking and heating has gone up from 6.6 percent in 1978-79 to 11.5 per cent in 1983-84.

Table 2.5: Fuel share for cooking and water heating (%)

	1978/79	1983/84
Firewood	42.4	27.4
Softcoke	18.4	15.3
Kerosene	18.7	35.7
LPG	6.6	11.5
Others	13.9	1.0

Shares are on a coal replacement basis for cooking and heating.
Source: TERI, op. cit Ref. Table III 5.6.

Transport sector: Transport sector has accounted for the largest share of oil consumption since 1960-61. The share of oil in total energy consumed by the transport sector more than doubled between 1953-54 and 1978-79. Among the oil products, HSD is the main source of commercial energy in the transport sector. Consumption of HSD - more than 90 per cent of which is consumed by road and rail transport-has grown at the rate of 8 percent per annum between 1980-81 and 1988-89. The increase in the share of oil has been entirely at the cost of coal (share of coal has declined from 56.4 per cent in 1953-54 to 13.3 per cent in 1978-79). In absolute terms, coal consumption in transport sector fell from 12.7 MMT in 1973-74 to 7.9 MMT in 1986-87. Steady decline in the use of coal in the transport sector since 1960-61 has been primarily because of phasing out of steam engines and replacing them with diesel or electric engines. The share of electricity in the energy consumption has remained unchanged in the period 1960-

61 to 1975-76.

Industrial sector: Most of the rise in energy consumption - almost a half in 1955-1970 and three quarters in 1970-71 - went to industry. This was due not only to industrial growth but also a rise in its energy intensity. The energy intensity for the industrial sector (defined as the ratio of total commercial energy consumed per unit of value added in the industrial sector) is given in Table 2.6.

Table 2.6: Energy intensities in Industrial sector

Year	Intensity of commercial energy consumption	Intensity of electricity consumption
1960-61	1.86	0.54
1965-66	1.99	0.74
1970-71	2.11	0.95
1975-76	2.40	1.02

Source: Report of the Working Group on Energy Policy, 1979

During fifties and sixties, coal supplied about half the energy needs of the industrial sector. The share of coal consumed by industrial sector increased from 48.1 per cent in 1953-54 to 78 per cent in 1984-85. About 20-30 per cent of the coal consumed in the industries sector is accounted for by a single industry, viz. steel; cement industry accounts for over 5 percent). During the period 1953-54 to 1960-61 oil consumption was between 16-18 per cent and that of electricity varied between 22-29 per cent. Since 1970-71, there has been a change in the fuel consumption-mix in the industrial sector. The share of oil and coal in the energy consumed by industries has been on a decline since 1970-71. Decline in coal consumption is due to fall in high quality coal. Due to the predominance of coal of poor quality and current pattern of growth of Indian economy, most of the incremental coal production is consumed by thermal power stations. As against coal and oil, electricity consumption in industries has been growing at a very rapid rate since 1970-71. In fact, increase in electricity consumption is the main reason for the rise in intensity of commercial energy consumption. Of the total commercial energy consumed by the industrial sector in 1978/79, electricity accounted for little less than 50 per cent.

Agriculture sector: Oil is the main source of commercial energy for the agricultural sector. It is used in tractors for tillage and for transport and pumps for lifting water. In 1953-54, share of oil consumption among other commercial energy sources was 89 per cent. By 1978-79, though its share had declined, but it still was quite substantial (62 percent). The share of electricity in commercial energy consumed increased steeply from 11 per cent in 1953-54 to 38.2 per cent in 1978-79. This share was exceptionally high in 1970-71 (50.2 percent). Today, the number of electric pump sets have outnumbered the number of diesel pumpsets.

CHAPTER 3

ENERGY PRICING POLICIES IN INDIA

3.1 Basic pricing objectives

The basic objectives that the energy pricing policy in India aims to subserve are :

1) Economic efficiency
2) Social Equity and
3) Financial viability

The efficiency principle seeks to ensure the regulation of pricing in a manner as to acheive an optimum allocation of society's resources to the energy sector. The equity principle pertains to welfare and income distribution considerations. This essentially equals charging differential prices to different user groups on the grounds of basic needs or establishment of uniform prices inspite of differential cost of supply often justified in terms of regional equity or similar goals. The financial principle suggests that the energy supply systems should be able to generate adequate revenues to remain financially viable, with a view to maintain current operation, a good quality and to provide scope for modernisation and expansion of activities in future. Another objective in this respect, may be to use the taxation of energy resources as a means of raising revenues for the government either to finance energy related facilities or to contribute to the general pool.

3.2 Hydrocarbon pricing

Till the early seventies, the Indian oil scene was dominated by multi-national oil companies. Thereafter, indigenous public sector oil companies took over charge of the oil industry from them. Starting from 1950, when an attempt was made for the first time to regulate oil prices till 1976, petroleum product prices were fixed on 'import parity' basis due to high dependance on imported crude oil from West Asia. However, the Oil Pricing Committee 1976 recommended against the import parity principle chiefly because indigenous production of crude oil was becoming increasingly important. Untimately, it suggested the concept of 'retention pricing' for petroleum sector.

Today, petroleum prices are fixed by the government and revised from time to time, for various stages of the supply industry. Pricing of petroleum products is based on the concept of 'retention pricing', taking into account the delivered cost of crude oil, its refining costs and some reasonable rate of return on the capital employed. The 'retention concept' is extended to cover distribution and marketing activities also. The oil refining and marketing organisations are compensated as suggested by the OPC, 1976 and subsequently updated by OCC and accepted by the Government. These prices are administered through a series of pool accounts. The price of the resource i.e. crude oil,to be paid to the petroleum exploration and production organisations is decided on the basis of their cost of operation, price of imported crude oil and a reasonable margin for expanding future exploration and production activities.

The second stage involves 'transfer pricing' i.e. price paid for crude oil by refineries to the producers. This is determined by means of pooling the prices of indigenous and imported crude oil and relates essentially to sharing of 'economic rent' arising due to the use of an exhaustible resource between producing and refining organizations. The third stage pertains to 'output/product pricing' whereby the retention prices for refineries are set keeping in mind the product mix to be attained with respect to their demand, while ensuring the financial viability of the refining companies. Similar concept is adopted for fixing retention prices for organizations engaged in distributing and marketing of products. The final stage relates to 'consumer pricing' which are fixed on the basis of certain social considerations.

3.3 Coal pricing

Coal prices have been administered by the government since 1941 except for a seven year period of decontrol between 1967 and 1974. During the phase of decontrol coal prices were mainly dictated by its principal buyers, namely railways for steam coal & steel plants for coking coal. The coal sector was nationalised in 1973. Since then coal prices have been revised several times on the basis of recommendations of several committees and working groups set up by the government. In general, all committees have recommended that pithead price of coal should be based on its average cost of production, with some return on the capital employed. Suitable allowance for cost escalations is also suggested. The basis of determining average cost of production has varied, depending upon the recommendations of the different committees of the government.

Presently the pithead price of coal is based on average cost of production for the industry, differentiated between grades of coal depending upon properties such as ash content or useful heat value. To determine average cost of production certain subjective standards have been adopted as "normative costs" for each of the element of production cost. These "normative costs" are close to the mean of observations of cost of producing coal in India. Pithead coal prices include loading and other handling costs. The pricing procedure focuses only on pithead costs with the delivered price of coal left largely uncontrolled.

Delivered price of coal to the consumer is determined by pithead prices plus transportation costs, taxes and duties. Due to geographical concentration of coal fields in the eastern parts of India, coal is transported over long distances. The average length of a haul for non-coking coal to power stations, cement plants etc. delivered by rail, is as high as 700 kms while that for coking coal is much shorter because steel plants are located relatively close to coal fields. Hence, the share of transportation cost in total delivered price (specially in case of non-coking coal) is quite high. Besides, the delivery price of coal is also inclusive of royalty payments, local cesses, excise duties and central and state taxes.

3.4 Electricity pricing

The electric utility industry in India is largely under the control of the state electricity boards, each of which has its own set of tariffs. The electricity tariff of the SEBs is to be primarily based on consideration contained in section 23 of Indian Electricity Act 1910, and section 40 and 59 of the Electricity (supply) Act 1948, Under the Electricity (supply) Act of 1948, the board has to carry on its operations, as far as practicable, without incurring losses and the board could adjust its tariffs from time to time. The Act did not mention any surplus that the board was expected to generate.

The electricity (supply) Act 1948 was amended in 1978 to make SEBs commercially viable and to earn a net return on their investment. In accordance with the amendment SEBs were to carry its operations and adjust tariffs as to ensure that total revenues in any year shall have such surplus as the State Government may from time to time specify. There was another amendment to the Act in 1980, which specified that the SEBs should earn a net return of 3 percent on the net assets as at the beginning of the financial year.

Several committees have been constituted in the past with the prime objective of analysing the financial performances and pricing policies of the power sector and to make recommendations to improve the operational and financial performance of the SEBs. Some of the recommendations of few committees set up in past are given below.

1. A working group set up by the Planning Commission in 1963 on Price Policy of the state electricity undertakings had recommended that the SEBs should earn a return of 12 percent (including electricity duty) on capital investments after providing for operating expenses and depreciation.

2. Venkataraman Committee in 1964, recommended a rate of return of 11 percent on the capital employed and suggested that this rate of return should be achieved in a phased manner within the next 10 years. This return was to be computed after providing for operating cost and depreciation. The net return worked out to be about 3 percent, after providing for interest charges (6 percent), transfer to general reserve (0.5 percent), electricity duty (1.5 percent). In several discussions with the World Bank, a rate of return of 11 percent as recommended by Venkataraman Committee has been mutually agreed upon.

3. The Rajadhyaksha Committee in 1980, recommended a rate of return of 15 percent on the average capital employed, responding to the rise in interest burden.

The theoretical advantages of LRMC-pricing are that it provides correct signals to producers and consumers of electricity and aids optimal resource allocation, as it emphasizes the costs incurred (or saved) by every consumption decision at the margin. In practice, however, electricity tariffs in India, as in most developing countries, are laid down on the basis of average cost approach. While laying down the tariffs,the SEBs, have to take into consideration the policies and objectives of their state governments. As a consequence tariffs are often weighed more by social considerations rather than financial and one finds that tariffs are therefore set at a rate even lower than the average cost of generation.

In order to ensure fair allocation of costs among the consumers according to the burden they impose on the system, the SEBs resort to differential pricing, However, due to some social and political reasons, the prices for certain consumer categories are set even below the average cost of power generation and supply to that category. For instance, tariffs are lowest for the agricultural sector though the cost of power supply to this sector is the highest. Average revenue realised from sales to the domestic sector also continues to be below cost for all the SEBs.

In order to make up the losses (only partly) that SEBs incur from agricultural and domestic consumers, the HT industrial and commercial consumers are often charged a tariff higher than the average cost of supply to them. The LT commercial consumers continue to pay rates higher than the average revenue realised in all SEBs. In several SEBs the average revenue realised from this category is even higher than that realised from industries. Furthermore, an analysis of tariff in some SEBs indicates that the LT commercial rates are even higher than the HT industrial rates.

Though the state utilities have their own sets of tariffs, the structure of tariffs are broadly similar. Consumers availing supply at low voltage (e.g. residential, commercial etc.) are generally charged an average energy rate (p/kwh) for the energy consumed and are billed for the energy they consume during a fixed period (generally 2 months). Most of the SEBs have a two-part (demand charge as well as energy charge) tariff for the industrial high voltage consumers (large industries, large business consumers, water supply, traction etc.). These consumers are charged an energy rate for the energy consumed during the billing period (normally one month). In addition, they are also charged a maximum demand reached during the billing period. A point to note is that the MD charge is generally not related to the time of incidence of maximum demand. Also, though the concept of time-of-day rates is well accepted, this practice has not been adopted in general in India, so far. Implementing such tariff structure requires sophisticated metering system which can record demand and energy separately for different time periods.

LT industrial consumers are differentiated on the basis of either the connected load or on the basis of BHP connected. Consumers with a higher connected load are charged a higher rate. The wide variation in rates across states is to be noted. The HT consumers are categorised on the basis of voltage of supply and/or the contracted demand. All boards have a power factor correction clause for HT and LT consumers. While most of the boards have a penalty for low power factor. Gujarat Electricity Board is one boards which has an incentive for improving the power factor.

Agricultural tariffs have always been the subject of considerable discussion. This category of consumption has a very significant seasonal aspect, apart from this, the load is scattered and the annual level of utilization is comparatively low. All boards have followed a policy of subsidized rates for agricultural consumers. Apart from the overall tariff being much below the average costs, another important feature of agricultural tariff is that it is framed in the form of a "flat rate" tariff. The consumer in this category are charged a flat rate based on their connected load (per HP of pumpset) irrespective of the number of hours used or energy consumed. This is against the basic economic principles, as the marginal cost of usage of the pumpset is zero in such a case. Also flat rate tariffs encourage misuse of electricity as well as encourage wastage of electricity. There are several instances of farmers running small industries on agricultural connection.

Most of the utilities, today, have moved from a simple energy rate to differential rates for different blocks of consumption. Inverted block tariffs are used to discourage consumption, as consumers have to pay an increasing charge for consuming more. This also takes care of the social objective of providing electricity at a low cost to consumers in the low income categories. There are one or two states who have decreasing block rates for domestic consumers. This is mainly done with a view to promote consumption amongst domestic consumers.

All boards have a fuel adjustment clause in their tariffs. But the increase in costs is passed on to all categories other than domestic, agricultural and LT industry categories. However, in Gujarat, fuel cost increases are passed on to all consumer categories. In Bihar, apart from HT consumers, the LT industry category also bears a share of the increase in fuel cost.

The present tariff structure in most of the SEBs is not remunerative enough to enable the boards to earn even the statutory 3 per cent rate of return. The SEBs get a subsidy from the state governments for meeting the part of the losses incurred by supplying to consumers below cost. This poses serious constrains on the resources that are required for adding to capacity, particularly in view of the increasing cost of capacity addition. Also, the low levels of tariff have encouraged high demand for the electricity. An appropriate tariff structure can play a significant role in demand management and electricity conservation.

Chapter 4

ENERGY SECTOR IN BANGLADESH

4.1 Energy sources in Bangladesh

Primary commercial energy sources in Bangladesh, comprise indigenous natural gas and hydropower and imported crude oil, refined products and coal. However, as in India, major proportion of the total energy requirements (approximately 60 percent) in Bangladesh are met by traditional energy sources. such as firewood, crop residues and animal wastes.

The combined contribution of all commercial energy sources to energy supplies increased from 3.41 mtoe in 1982 to 4.98 mtoe in 1987 registering an average growth rate of 7.77 per cent per annum. Table 4.1 gives the details of indigenous production, exports and imports of various sources of commercial energy. Natural gas is the main source of commercial energy in Bangladesh. Its production increased from mere 0.44 million cu.m. at the time of independence (1971) to 0.69 million cu.m. in 1974 (an average growth rate of 13.2% per annum). Natural gas production fell down drastically by 33.7 per cent in 1975 but soon picked up and increased at an average growth rate of 10.9 per cent during 1976-79. In 1987, total natural gas production in Bangladesh was 3.5 million cu.m. (3 mtoe). Based on data relating to 13 gas fields, all of which are located in the eastern side of the Padma-Jamuna river complex (the east zone), recoverable reserves of natural gas are estimated at about 19 trillion cubic feet (tcf), of which 10.4 tcf are proven and probable reserves. Exploration for gas in the

Table 4.1: Energy balance in Bangladesh ('000 toe)

	1975	1977	1979	1980	1982	1983	1984	1985	1986	1987
A. Coal										
- Indigenous production										
- Imports	125	123	89.5	124	154.5	87.3	34.9	49	74	32.5
- Exports										
B. Oil										
- Indigenous Production	5	7	7	0	0	0	0	81.3	93.5	111.9
- Imports	1233.5	1384.9	1443.5	1757.1	1890.4	1559.5	1575.9	1635.5	1817.9	1908.6
- Exports	-46.6	-136.6	-61.3	-92.5	-183.3	-141.5	-94.6	-96.6	-96.4	-73.9
C. Gas										
- Indigenous Production	390.9	703.7	853.9	1083.8	1550.6	1723.9	1987.3	2264.6	2553.2	3000.6
- Imports										
- Exports										
D. Electricity	135.6	161.2	200.2	196.1	253	286.1	130.5	405.8	427.1	491.3
Total availability	1863.4	2243.2	2532.8	3068.5	3665.2	3515.3	3834	4339.6	4869.3	5471

Source: World Energy Statistics and Balances 1971-1987.

west zone has not yielded any favourable results so far.

Bangladesh has some potential coal and peat resources as well. However, due to the depth, development of these coal fields is, at present, uneconomical. The entire coal consumed in the country is imported. In 1975, 0.125 mtoe of coal was imported. The availability of coal as a source of commercial energy in the total availability of commercial energy sources was 6.7 per cent in 1975. This percentage has been on a decline, and was 0.6 per cent in 1987. In 1987, 0.032 mtoe of coal was imported by Bangladesh. Substantial decline in import of coal is indicative of the government's policy of reducing dependence on expensive imported energy. As against coal, the import of hydrocarbon has been on an increase. In 1975, 1.25 mtoe of oil was imported, in 1980 the figure was 1.76 mtoe and in 1987 oil import in Bangladesh was of the order of 1.908 mtoe. However, the ratio of oil import to the total commercial energy available in the country declined from 0.67 in 1975 to 0.57 in 1980 and further to 0.35 in 1987. In order to increase indigenous oil production many seismic surveys and geological studies are being carried out. The government is taking all efforts to attract international oil companies to undertake petroleum exploration in Bangladesh.

Bangladesh's hydropower potential is limited. Natural gas and furnace oil are primarily used to generate thermal power. The installed capacity in the country has grown from 547 MW in 1970-71 to 1957 MW in 1987-88, comprising 230 MW of hydroelectric and 1727 MW of thermal capacity. Trends in electricity generation since 1975 are given in Table 4.2. Share of hydro-electricity in total

Table 4.2: Trends in electricity generation (in GWh)

Year	Oil	Gas	Hydro	Total
1975	531 (32.6)	660 (40.6)	436 (26.8)	1627 (100)
1977	597 (30.9)	900 (46.5)	437 (22.6)	1934 (100)
1979	719 (30.0)	1096 (45.6)	587 (24.4)	2402 (100)
1980	626 (26.6)	1144 (48.6)	583 (24.8)	2353 (100)
1982	745 (24.5)	1758 (58.0)	533 (17.5)	3036 (100)
1983	632 (18.4)	2139 (62.3)	662 (19.3)	3433 (100)
1984	734 (18.5)	2335 (58.9)	897 (22.6)	3966 (100)
1985	822 (16.9)	3309 (67.9)	739 (15.2)	4870 (100)
1986	1313 (25.6)	3362 (65.6)	450 (8.8)	5125 (100)
1987	2065 (35.0)	3300 (56.0)	530 (9.0)	5895 (100)

Percent share in the total electricity generated in brackets

electricity generated has declined from 26.8 per cent in 1975 to 9 percent in 1987, whereas the share of electricity generated from gas-fired power plants has increased from 40.6 per cent in 1975 to 56 per cent in 1987 (share of gas-based electricity was highest in 1985 (68 percent)). Proportion of electricity generated from oil based power stations has also been on a decline since 1975; its share declined from 33 per cent in 1975 to 17 per cent in 1985. However in 1986, its share suddenly increased to 25.6 per cent and further increased by 10 per cent in the following year.

4.2 Trends in energy consumption

The past pattern of final commercial energy consumption in Bangladesh on oil equivalent basis is shown in Table 4.3. It is evident that oil was the prime source of commercial energy in 1970's. The share of oil in total primary energy consumption reached a maximum level of 66.4 per cent in 1975. Since then the share of oil has been on a decline. In 1987, the share of oil in final energy consumption was almost half (33.9 percent) of that in 1975.

Table 4.3: Final energy consumption in Bangladesh ('000 toe)

	1975	1977	1979	1980	1982	1983	1984	1985	1986	1987
Coal	125	129	93	124	155	87	35	49	74	33
	(9)	(7.8)	(5.0)	(5.6)	(6.1)	(3.6)	(1.4)	(1.7)	(2.4)	(0.9)
Oil	926	967	1146	1262	1224	1147	1112	1238	1279	1211
	(66.4)	(58.5)	(60.8)	(57.3)	(50)	(47.0)	(43.1)	(43.9)	(40.8)	(34)
Gas	246	449	511	698	998	998	1199	1263	1464	1946
	(17.6)	(27.1)	(27.1)	(31.6)	(39)	(41.0)	(46.5)	(44.7)	(46.8)	(54.5)
Electricity	98	110	134	121	175	206	232	272	312	380
	(7.0)	(6.6)	(7.1)	(5.5)	(6.9)	(8.4)	(9.0)	(9.7)	(10.0)	(10.6)
Total	1395	1653	1884	2205	2552	2438	2578	2822	3129	3570

Figures in brackets are in percent

Reduced dependence on oil has been accompanied by a rising share of natural gas as a source of energy. The share of natural gas in final energy consumption increased significantly from 17.6 per cent in 1975 to 31.6 per cent in 1980 and in 1987 more than half (54.5 percent) of the final energy consumption was met by natural gas. Thus, we find that the relative positions of oil and gas more or less reversed between 1970 and 1987.

Coal consumption in Bangladesh has always been very low. Its share in final energy consumption declined further from 8.9 percent in 1975 to 5.6 percent in 1980 and to 1 percent in 1987. Share of electricity in final energy consumption, in 1975, was lowest among all commercial energy sources (7 percent). Its share remained almost stable till 1982. However, since 1983, electricity intensity of the country is increasing. Share of electricity consumption in 1987 was 10.6 per cent, of the final commercial energy consumed.

Final commercial energy consumption accounted for 62 per cent of the total commercial energy available in 1986. Remaining 38 per cent of commercial energy was used in petroleum refining, power generation and in other transformations. Out of the total supply of 2553.2 toe of natural gas 952.2 toe (37.8 percent) was used in generating electricity. 21 per cent of the total oil supplies was used to generate power, 9 percent was used in petroleum refining and the remaining 70 per cent was used for final consumption.

4.3 Energy consumption by end-use

Table 4.4 shows final energy consumption by end-use in Bangladesh. Industrial sector is the prime consumer of commercial energy. In 1986, industrial sector consumed little more than 50 per cent of the total final commercial energy consumed in the country. Almost entire coal imported by Bangladesh is consumed by the industrial sector. Industrial sector is followed by domestic sector; in 1986 domestic sector accounted for 20 per cent of the total commercial energy consumption. The share of domestic sector in commercial energy consumption has been declining gradually. Agriculture sector has a very small share in final commercial energy consumption. However since 1980, there has been a slight increase in the intensity of energy used in agricultural sector.

Table 4.4: Final energy consumed by end-use ('000 toe)

	Coal	Oil	Gas	Electricity	Total
1980					
Domestic	0	410.9	62.4	19.6	429.9
Commercial	0	0	25.4	0.9	26.3
Agriculture	0	96.3	0	2.5	98.8
Industry	124	350.0	610.0	75.8	1159.8
Transport	0	374.2	0	0	374.2
Non-energy use	0	30.7	0	0	30.7
1986					
Domestic	0	388.5	162.8	81.9	633.2
Commercial	0	0	58.8	7.6	66.4
Agriculture	0	207.0	0	14.6	221.6
Industry	74.0	94.8	1242.1	176.4	1587.3
Transport	0	512.7	0	0	512.7
Non-energy use	0	75.8	0	0	75.8

Source: World Energy Statistics and Balances 1971-1987.

Share of agricultural sector increased from 4.5 per cent in 1980 to 7.1 per cent in 1986. This increase has been brought about by significant increase in the consumption of the oil as the source of commercial energy in the agriculture sector. Though the commercial energy consumption by the commercial sector has been on an increase since 1980, it still accounts for a very low proportion of the total final energy consumed. (in 1986, barely 2 percent of the total commercial energy was consumed by commercial sector). Natural gas is the prime source of energy consumed by this sector. In 1986, natural gas accounted for 89 per cent of the total energy consumed by the commercial sector.

There has been significant structural change in the consumption pattern of electricity among different consumer categories. Table 4.5 gives the trend in electricity consumption by end-use. The share of domestic consumption has increased from 18.3 per cent in 1982-83 to 22.9 per cent in 1985-86. As against this, the share of large industrial and commercial consumers has gone down substantially from 58 per cent to 42 per cent during the period (1982-83 to 1985-86). The share of agriculture is extremely small (1.6 percent) and has remained more or less stable during the same period. The share of small industries and small commercial consumers also, has not changed much during this period.

Table 4.5: Break-up of energy sold by BPDB

Consumer Category	% of energy sold 1982-83	1985-86
Domestic	18.3	22.9
Small industrial	9.4	9.6
Small commercial	9.8	8.4
Large industrial & Commercial	58.0	42.5
Agriculture	1.6	1.6
Others	2.9	1.5

4.4 Power sector in Bangladesh

In Bangladesh, power planning, generation and its distribution is the responsibility of Bangladesh Power Development Board (it was formed in 1972). BPDB distributes electricity in all areas except some rural areas which are instead served by the Rural Electrification Board (REB). REB was created in 1977 and it distributes power in rural areas through a system of co-operatives, Palli Biduyt Samities (PBSs).

Bangladesh electricity system has developed in two separate parts, in the east and the west zone. The power systems in the two zones were interconnected in December 1982 by a 230 kV double circuit transmission line. BPDB's annual energy sales increased from about 2399 GWh in 1983 to 3773 GWh in 1988 at a rate of 9.5 percent per annum. Peak demand increased from 709 MW to 1317 MW during the same period. The total number of consumers connected by BPDB system (including bulk power purchases at 33 kV from REC) increased from 669 lakhs in 1983 to 1038 lakhs in 1988.

4.5 Electricity Pricing

Electricity tariffs are laid down by BPDB and are uniform throughout the country. In addition to BPDB, PBSs sets their own tariffs with the approval of REB.

As in the case with most developing countries, in BPDB also the electricity tariffs are uneconomical. Cost of operations have been higher than revenues realized. BPDB has been incurring substantial losses and this has been attributed mainly due to the inability to keep tariffs at a level consistent with the costs. Another important factor contributing towards low level of revenue realization is high system losses. During 1980-81, system losses were approximately 40 per cent of gross generation, declining to about 37 per cent in 1985-86. In 1988, however, the losses again increased to 42.4 per cent. Technical losses in distribution system are reported to be high due, in part, to inadequate investment in distribution facilities in addition to investments in transmission. Inadequate metering, improper billing and pilferage are the main causes of high level of non-technical losses.

In 1978-79, net revenue losses were Tk 293.6 million and this amounted to 45 per cent of the total revenues (this reduced to 27 percent in the following year). After a long period of operational deficits, BPDB showed a net operating income of Tk 561 million during FY 1983, and the rate of return on the historical asset base was about 8.2 percent. This was partly due to an increase in the revenue income, as well as savings in the cost of fuel. Increase in revenue income was brought about from a 28 per cent increase in the average tariff level and a reduction in system losses. Savings in fuel costs were possible due to the commissioning of east-west interconnection (there is wide variation in the BPDB's fuel costs in the east and west zones). This positive trend continued until 1985-86. The share of fuel cost reduced from 61 per cent in 1982-83 to 54 per cent in 1985-86. In 1986-87, there was a sudden jump in the fuel costs due to lower water availability in the hydropower plants. As a result of this BPDB incurred a net operating deficit of Tk 285 million (5 percent of the total revenues). Situation improved in the following year with BPDB earning a net operating income of Tk 556 million. Return on historical asset base in 1988 was 3.40 percent. Net operating income of Tk 812 million was realized in 1988. Table 4.6 gives details of average revenue and cost per unit of electricity sold for the period 1981-82 to 1985-86. There is clear indication that revenues have increased faster than costs. Average revenue have increased at an average annual growth rate of 13.5 per cent and average costs have increased at an average annual growth rate of 10 per cent.

In recent years, BPDB has made serious efforts to simplify tariffs and relate them to the cost of supply. The BPDB's tariffs were raised by 38 per cent in September 1979, by 40 per cent in October 1980 and by a further 40 per cent in July 1982. It is interesting to note that tariff revisions are carried out annually. The tariffs were increased by 3.2 percent in 1983, by 9.5 percent in March 1984, by 3.4 percent in December 1984 and by 16.4 per cent in September 1985.

Table 4.6: Average revenue and average cost of supply for BPDB

Year	Average revenue (Tk/KWh)	Average cost (Tk/kWh)
1981-82	1.00	1.19
1982-83	1.28	1.10
1983-84	1.29	1.12
1984-85	1.40	1.33
1985-86	1.66	1.75

Source: Comparison of electricity policies in developing countries,TERI

A new simplified set of tariffs was introduced in August 1987, where BPDB's average tariff rate was raised by 15 per cent bringing it to about 70 per cent of the economic cost of supply. The number of tariff categories were reduced from 18 to 10 and the sizes of the subsidized blocks of energy consumption of residential consumers were also reduced. In addition, a new two-part time-of-day tariffs for 33kV and 11kV consumers was introduced. Time-of-day tariffs for large low voltage consumers was also introduced. A comparison of tariff structure in force in July 1982 and in August 1987, is made in Table 4.7.

REC also revised the tariffs for supplies to rural areas in May 1987. The electricity rates were increased by an average of 20 per cent. Further, in July 1987, the tariffs were restructured to include (i) a new tariff category for high-voltage consumers; (ii) a time-of-day tariff for large low voltage consumers; and (iii) a three-block increasing tariff for residential consumers.

Table 4.7 : Comparison of electricity tariffs

Consumer category	July 1982	August 1987
Domestic	0.50 (0-50 kWh)	1.25 (0-70 kWh)
	0.60 (51-250 kWh)	1.40 (71-200 kWh)
	0.70 (251-400 kWh)	2.85 (> 200 kWh)
	2.00 (>400 kWh)	
Agriculture	.50 (0-250 kWh)	1.70 all energy without TOD
	1.00 (> 250 kWh)	1.35 TOD off-peak rate/kWh
		4.00 TOD peak rate/kWh
Small industry	1.50	2.30 all energy without TOC
	1.10	2.00 TOD off-peak rate/kWh
	4.00	4.25 TOD peak rate/kWh
Commercial consumers	1.40 (0-100 kWh)	2.80 all energy without TOC
(Hospitals & Educational institutions etc.)	2.50 (> 100 kWh)	2.00 TOD off-peak rate/kWh
		5.40 TOD peak rate/kWh

An important feature of BPDB tariff is that the fixed cost of power generation and supply is recovered through a service charge from each category. In addition to the energy charges, demand charge based on the sanctioned load is levied on all consumer categories except high-voltage bulk supply of electricity to REB/PBS, who in turn supply electricity to rural areas. Demand rate for supply at 6350/11000 volts is levied on the basis of maximum demand. BPDB has a fuel adjustment clause to account for increase in fuel prices. This clause is applicable to all consumer categories. In order to encourage the consumers to maintain unity power factor as nearly as practicable, BPDB levies a penalty, on consumers whose power factor fall below 0.95.

Some of the important features of tariffs in BPDB for different consumer categories are listed below:

Domestic consumers: These consumers have an increasing block tariff. The number of blocks have been reduced from four (in July 1982) to three in 1987. Domestic consumers are charged energy rate based on kWh of energy consumed and a demand rate based on their connected load (except for consumption less than 70 kWh). A life line rate of Tk 1.25 per kWh is charged to consumers with consumption less than 70 kWh per month. The rates for the lowest block has undergone a steep increase from Tk .50 per kWh in 1982 to Tk 1.25 per kWh in 1987. Even for the other consumption blocks there has been a substantial increase in the tariffs.

Commercial consumers: Commercial consumers are required to pay demand charge in addition to an average energy rate for all units consumed. Consumers with sanctioned load of more than 50 kW come under time-of-day rates. Consumers facing time-of-day rates are charged a peak rate equivalent to 2.7 times more than off peak rate. Special concessional rates are levied for hospitals and educational institutions.

Agricultural consumers: Agricultural tariffs in BPDB have a seasonal component. During off-irrigation season tariff is levied on the basis of the actual energy consumed or a flat rate, which ever is higher. Demand and service charges are not applicable during off-irrigation season. Time-of-day rates are applicable for agricultural consumers too. The rates for the agricultural consumers have also undergone a substantial increase (see Table

4.7 for details).

Small industrial consumers: This category comprise industrial consumers with sanctioned load upto 50 kW. These consumers have a demand charge based on sanctioned load (for more than 20 kW of connected load) and peak and off-peak energy rates. During the period 1982-1987, peak energy rate has gone up by 6.25 percent and the rate for off-peak consumption has increased by almost 82 per cent.

HT consumers: Separate rates are levied for medium voltage general purpose, high voltage general purpose, EHV general purpose, and high voltage bulk supply categories. All HT consumers have time-of-day rates. The EHV consumers have a higher peak to off-peak energy rate as compared to HV consumers. Rate for bulk supply consumers has not undergone a significant change.

To conclude, Bangladesh is one of those few among the developing countries to have introduced innovative features in electricity tariffs, most notable features being introduction of time-of-day tariffs and an element of seasonality in agricultural tariffs.